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IDAHO PUBLIC
UTILITIES COMMISSION

Attorney for Renewable Northwest and American Wind Energy Association

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY TO UPDATE ITS WIND INTEGRATION RATES AND CHARGES.	) Case No. IPC-E-13-22)) COMMENTS OF AWEA AND) RENEWABLE NORTHWEST)

I. INTRODUCTION

Pursuant to Idaho Public Utilities Commission ("IPUC" or "Commission") Rule of Procedure 203 and the Modified Procedure Schedule agreed to by the parties on May 27, 2014, the American Wind Energy Association ("AWEA") and Renewable Northwest[1] hereby file these Comments on Idaho Power Company's ("Idaho Power" or the "Company") November 29, 2013 Application to Update Wind Integration Rates and Charges (the "Application"). Idaho Power's Application seeks to increase the wind integration rates and charges applicable to qualifying facilities ("QFs") under the Public Utility Regulatory Policies Act of 1978 ("PURPA").[2] As originally presented to the Commission, the Application would modify the rates of both QFs

[1] Following the commencement of this proceeding, in recognition of the organization's twentieth anniversary, Renewable Northwest Project changed its name to "Renewable Northwest."
[2] *In the Matter of the Application of Idaho Power Company to Update its Wind Integration Rates and Charges*, Case No. IPC-E-13-22, Application at Part IV (Nov. 29, 2013).

with existing contractual legally enforceable obligations and any new wind generator QFs that may come online in the future.[3]

Several parties filed Motions to Dismiss the Application on the basis that it requested the Commission to modify the rates and terms in existing contractual legally enforceable obligations without the QFs' consent.[4] AWEA and Renewable Northwest filed comments in support ofdismissal and requested workshops to address the issues raised in the Application and accompanying Wind Integration Study.[5]

In Order No. 33030, the Commission denied the Motions to Dismiss, but clarified that any Commission-approved modifications to Idaho Power's wind integration rates and charges would only apply prospectively to new contracts.[6] The Order also provided that intervenors seeking to protect the rights of existing contracts could withdraw from the proceeding if they believed they no longer had a direct and substantial interest in the proceeding.[7] Although some intervenors withdrew from the proceeding, our organizations have remained involved to represent our continuing interest in accurate wind integration studies, discussed further below.

II. COMMENTS

Before addressing the merits of the Application, we wish to clarify our continued interest in this proceeding. Our organizations have been deeply involved with wind integration studies and proceedings on wind integration issues for many years. This proceeding is unique in that we

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[3] *Id.*
[4] *See, e.g., In the Matter of the Application of Idaho Power Company to Update its Wind Integration Rates and Charges*, Case No. IPC-E-13-22, Motion to Dismiss of Cold Springs Windfarm, LLC, *et al.* (Jan. 31, 2014).
[5] *In the Matter of the Application of Idaho Power Company to Update its Wind Integration Rates and Charges*, Case No. IPC-E-13-22, Comments of AWEA and RNP in Support of Motion to Dismiss (Feb. 7, 2014).
[6] *In the Matter of the Application of Idaho Power Company to Update its Wind Integration Rates and Charges*, Case No. IPC-E-13-22, Order No. 33030 at 8 (Apr. 30, 2014).
[7] *Id.*

do not expect the outcome to have a near-term impact on the rates associated with new wind development on Idaho Power's system, as we do not anticipate *any* new wind projects selling their output to Idaho Power under PURPA in the near-term—largely due to the current published rate cap and Idaho Power's onerous contractual provisions. Nevertheless, we have remained in this proceeding because of the fundamental flaws in Idaho Power's most recent Wind Integration Study (the "2013 Study") that underpins the Company's Application in this proceeding. It is in the public interest to ensure the technical accuracy of such studies, and failure to do so runs counter to the interest of ratepayers and shareholders alike.

Our Comments here focus on identifying the major flaws in the Company's 2013 Study and making recommendations on how to correct these flaws. The primary shortcomings of the 2013 Study are that it does not accurately portray Idaho Power's actual operating procedures or best practices by (1) using the day-ahead wind forecast error instead of the hour-ahead forecast error in calculating the reserve requirement for wind; and (2) calculating reserve requirements based on the outdated assumption that reserves accommodate wind variability on a stand-alone basis, when in reality, grid operators balance the deviations of net load (load minus wind and other generation).[8] In addition to these methodological flaws, the Company has not accounted for available operational tools that enable wind to be integrated more efficiently. Our analysis suggests that these methodological shortcomings result in a roughly three-fold exaggeration of the incremental reserve requirement for wind.

In connection with our analysis, we have performed some calculations on what we would expect the correct rates to be, and those rates are lower than those proposed in the Application. However, more information is needed to arrive at fully accurate rate calculations. What our

[8] We use the terms "balancing reserves," "reserve requirement," "Reg-Up," and "Reg-Down" all to refer to the same flexible generating capability necessary to accommodate the within-hour variability of load and generation (including wind, solar, and conventional generation).

calculations demonstrate is that the flaws in Idaho Power's 2013 Study result in excessive, inaccurate wind integration charges. We recommend that the Commission refrain from approving the Company's proposed wind integration rates and charges that would apply to any new QFs or be used in any integrated resource plan until such time as Idaho Power revises its 2013 Wind Integration Study to address the flaws identified herein.

1. Comparison of Idaho Power's 2007 and 2013 Wind Integration Studies.

Alarmingly, it appears that the Company's use of best practices in its wind integration methodology has actually diminished over the past seven years, as many of the errors in the 2013 Study were not made in Idaho Power's 2007 Wind Integration Study (the "2007 Study").

In the Company's 2007 Study, which includes the original Study and an Addendum,[9] the Company employed the services of the well-respected electric engineering and consulting firm, EnerNex. This earlier analysis was well grounded in sound practices and employed the then-current methodologies. Specifically, the 2007 Study appropriately relied on the hour-ahead forecast error for wind, and netted the variability of load, wind, and conventional generation to reflect the reality that balancing reserves are held for net load variability, which is far smaller than the sum of the parts of the reserve requirements for wind and load.

In preparing the 2013 Study, Idaho Power has abandoned the use of outside consultants to inform the study methodology and has instead chosen to pursue methodologies that are inconsistent with current utility practice and wind integration science. Most importantly, Idaho Power's 2013 Study does not incorporate the use of hour-ahead wind forecasts and fails to net the reserve requirements of wind and load; these methodological flaws are described in detail in the following two sections.

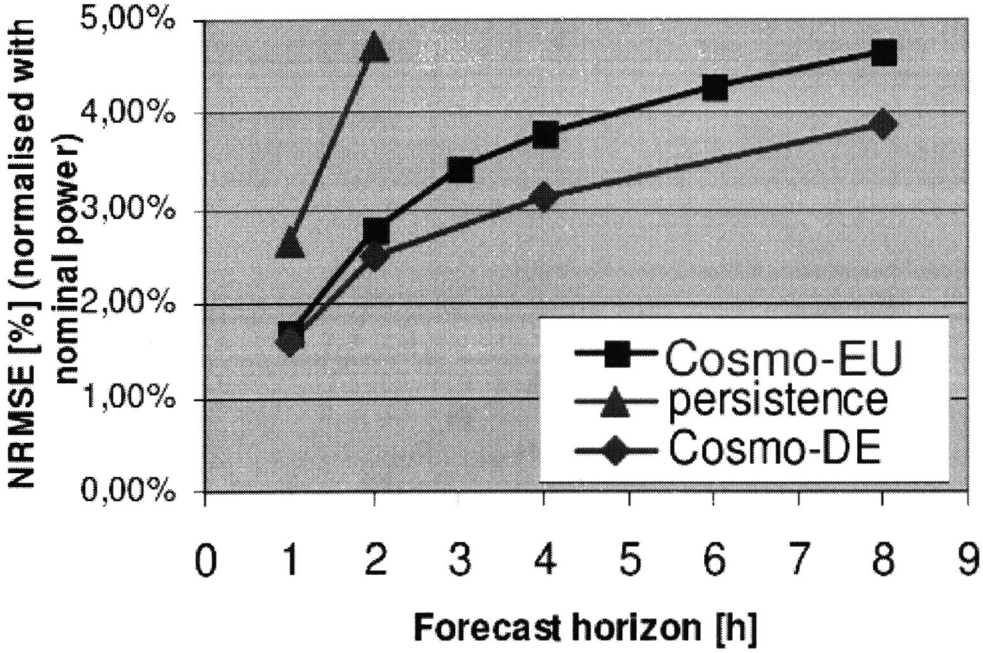
[9] Idaho Power's 2007 Study was conducted in February of 2007, and then updated with the Addendum in October of that same year.

As a general comment, we struggle to understand why Idaho Power has moved away from the well-established best practices for wind integration studies it used seven years ago, particularly given that most utilities have made strides in this area. Indeed, most utilities have greatly improved their wind integration operations over the past seven years by improving their wind forecasting and scheduling capabilities and by using dynamic approaches to committing and holding balancing reserves. In contrast, Idaho Power's 2013 Study suggests that the Company has become less efficient at integrating wind.

2. Use of Day-Ahead Versus Hour-Ahead Forecast Error.

One of the primary methodological errors in the 2013 Study, and a major driver of the costs identified by the Study, is the use of day-ahead forecasts to predict the output of wind plants. Use of "day-ahead" forecasts in this context means that system operators set their wind forecast for a given hour the day before the actual hour of production occurs. In contrast, "hour-ahead" forecasting uses wind forecasts set during the hour before the wind is generated. This is an important issue because hour-ahead wind forecasts are inherently more accurate than day-ahead forecasts. Indeed, it is a well-established scientific fact that wind energy forecast error is greatly reduced as one moves closer to real-time, as one would expect for any forecast.[10]

[10] For example, data from Germany show that the normalized root mean square error ("NRMSE") is reduced from 5.7% of installed wind capacity for a day-ahead forecast to 2.6% for a 2-hour ahead forecast. Hannele Holttinen, *et al.*, Design and Operation of Power Systems with Large Amounts of Wind Power at 28-29 (2009), *available at* http://www.vtt.fi/inf/pdf/tiedotteet/2009/T2493.pdf. Hour-ahead forecasts show even greater accuracy, with NRMSE falling well below 2% at a forecast horizon of one hour (as shown by the blue and brown lines in the EU chart, indicating the NRMSE for European and German wind energy forecast models respectively). *Id.* Closer to home, data from the Alberta independent system operator ("AESO") shows a nearly identical relationship, with wind energy forecast error falling drastically as one gets closer to real-time, as shown in the AESO chart. *See* R. Widiss and K. Porter, A Review of Variable Generation Forecasting in the West, NREL Report SR-6A20-61035 at 4 (July 2013), *available at* http://www.nrel.gov/docs/fy14osti/61035.pdf.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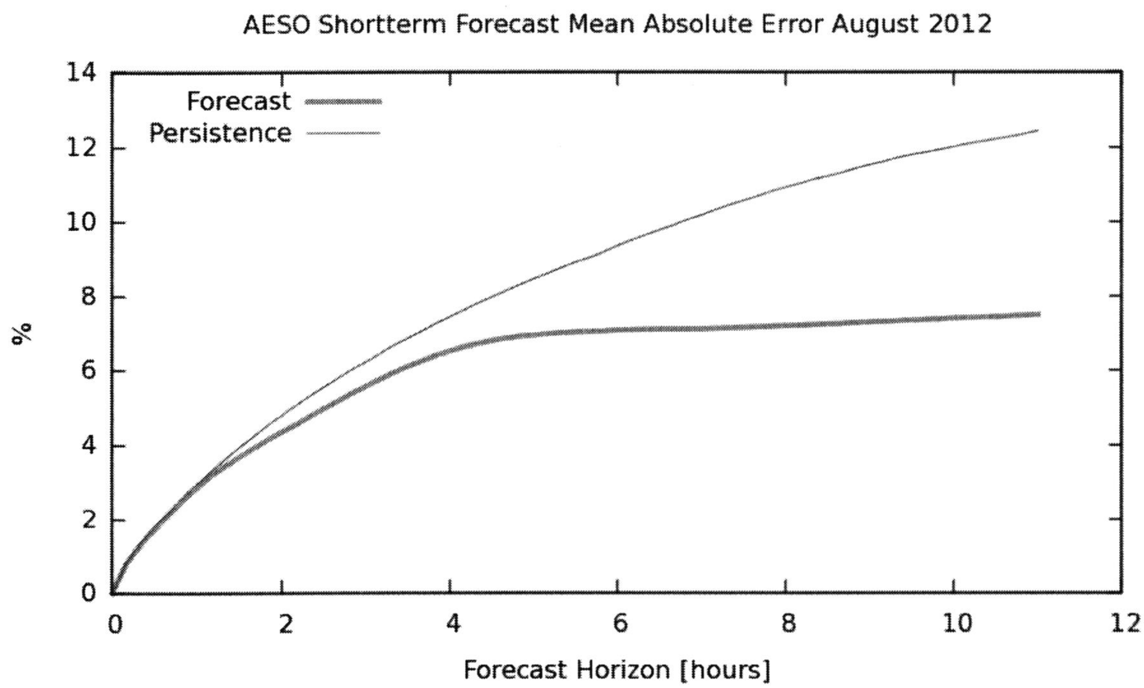
AESO Shortterm Forecast Mean Absolute Error August 2012
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Idaho Power's 2007 Study uses hour-ahead forecasts to calculate the integration costs—not day-ahead forecasts. Section 7 of the 2007 Study explains how the incremental reserve requirement for wind is input into the Vista DSS model: it assumes that the next-hour wind forecast is delivered to operations at 65 minutes before the next hour. The 2007 Study explains, "this allows the operations group time to assess, plan and execute transactions to meet next hour needs in a manner consistent with current trading practices."[11] In other words, the 2007 Study does not use the day-ahead forecast error to calculate the incremental reserve requirement need.

Using day-ahead forecasts, as Idaho Power does in the 2013 Study, is inconsistent with other wind integration studies and with common utility scheduling and dispatching practices. The effect of this methodological error is to greatly inflate the amount and cost of balancing reserves needed to integrate wind on Idaho Power's system. The impact of this methodological change in the 2013 Study can be observed by comparing the results of the two studies. For example, whereas the 2007 Study finds that 900 MW of wind would require an incremental reserve requirement of 98 MW of Reg-Up and 98 MW of Reg-Down, the 2013 Study finds that 800 MW of wind would require between 199-274 MW of Reg-Up and between 219-353 MW of Reg-Down. In short, the changes Idaho Power has made to the study methodology cause a roughly three-fold increase in the amount of balancing reserves needed for wind.

When asked about the rationale for basing the reserve requirement for wind on the day-ahead schedule error in the 2013 Study, Idaho Power responded:

> Idaho Power views the simulation of day-ahead scheduling as appropriate due to system scheduling practices. Day-ahead scheduling is reflective of the time frame in which Idaho Power makes dispatching decisions… [if not] … the amount of balancing reserves is smaller because it is based on the hour-ahead errors in forecast wind… [and so]… the dispatchable generators would not

[11] 2007 Study at 46.

> be scheduled to allow them to respond to day-ahead forecast errors, meaning that the response to these larger errors is only achieved by some other means, which in Idaho Power's view would too often translate to a risky reliance on the wholesale electric market.[12]

We disagree with Idaho Power's characterization of system scheduling practices, as it exaggerates the importance of day-ahead "scheduling." Standard utility practice is to "dispatch" generation close to real-time, while the day-ahead process of selecting which plants are likely to operate the next day is called "unit commitment." Unit commitment is very different from dispatch, as unit commitment typically only entails evaluating supply and demand to determine which units are likely to be needed the next day so that any units that require a long lead time to start up can begin to do so. Unit commitment decisions frequently deviate greatly from how power plants are dispatched the next day, as actual dispatch decisions change with evolving supply and demand conditions.

We understand that Idaho Power starts its system management with a day-ahead forecast for load, wind, other generation, and off-system transactions. However, Idaho Power is well aware that its day-ahead load forecast will be wrong and that it needs to have enough generation available to meet its load under all reasonable conditions. As the day unfolds, Idaho Power must adjust to real-time conditions and make hourly dispatch decisions to meet its load and all other contractual arrangements in a least-cost manner.

Indeed, any utility system is constantly changing its hour-to-hour dispatch to serve load reliably and at least-cost. Dispatchable generation has always been changed on an hourly basis to follow the net of hourly changes in load and deviations in the output of conventional generators, and operators use the same approach for following net load changes on systems with

[12] Idaho Power Response to Data Request No. 4.

wind. As the wind comes up, a utility will back off more expensive generation previously made available in the day-ahead timeframe to meet load, which saves the utility operating costs. As the wind drops off, a utility will increase the use of its more expensive generation, hour-by-hour, adjusting for the wind's output and mindful to not use any more higher-cost generation than necessary.

Because Idaho Power can use hourly adjustments from its other generators or market transactions to cover the hour-to-hour changes in net load, Idaho Power only needs to carry enough balancing reserves to cover the hour-ahead forecast error. This is why Idaho Power used hour-ahead forecasts to estimate balancing reserve needs in its 2007 Study.

When asked to provide all wind integration studies that Idaho Power relied upon in making the decision to base the study of reserve requirements for wind on the day-ahead scheduling/forecasting error, Idaho Power produced one paper from 2009.[13] Specifically, Idaho Power quotes from page 4 of that study, noting that, "a utility will make unit commitment decisions well in advance of real-time, based on wind forecasts and load forecasts, and will make additional decisions when correcting dispatch in real-time given the original commitment set."[14] Idaho Power's data response goes on to claim that, "consistent with the IEEE publication, Idaho Power makes unit commitment decisions in the day-ahead market... [and]... based the reserve requirement decisions for wind on the wind forecast day-ahead schedule error."[15]

As stated above, we do not disagree that utilities must make unit commitment decisions a day in advance of real-time, but the important aspect of system scheduling that Idaho Power leaves out—and which is clearly identified in the same sentence they quote from—is that a

[13] Idaho Power Response to Data Request No. 5 (citing Erik Ela, *et al.*, The Evolution of Wind Power Integration Studies: Past, Present, and Future at 1-8 (2009 IEEE)), *available at* http://ieeexpiore.ieee.org/xpi/loqin-isp?tp-&arnunnber=5275981&url=hUp%3A%2F%2Fieeexp!or.
[14] *Id.*
[15] *Id.*

utility "will make additional decisions when correcting dispatch in real-time." It is this real-time, hour-by-hour management of variable loads and wind that Idaho Power's current study completely ignores. While Idaho Power admits that it adjusts generation hour-by-hour for load,[16] the 2013 Study completely ignores this routine aspect of utility operations.

Furthermore, the IEEE paper relied on by Idaho Power makes no mention of basing the reserve requirement for wind on day-ahead schedule error. It says that the utility must make "unit commitment" decisions based on day-ahead forecasts of load and wind, but does not say that the commitment decision must be to hold a fixed amount of balancing reserves based on a day-ahead forecast error. Doing so would be hugely inefficient and would ignore all of the lower cost options available to the utility through the hourly dispatch of least-cost resources.

We agree that Idaho Power must set up the system in advance, a day-ahead, to be able to provide sufficient balancing reserves to manage the hourly forecasting error from wind and load, but that is not the same thing as needing to determine the hour-by-hour wind schedules a day in advance of real time and hold reserves based on that larger forecast error. Instead, the common practice in utility wind integration studies (and for most Northwest utilities) is to determine the maximum (90th percentile) amount of hour-ahead balancing reserves needed (based on a 45-, 30-, 15-, or 10-minute-ahead persistence forecast) and hold that amount every hour of the year. This approach recognizes that the hourly dispatch of other resources and market purchases will play a significant role in following the fluctuations in load and wind throughout the day. This approach would reduce costs significantly and is consistent with what Idaho Power did in its 2007 Study. Standard best practice in many regions of the country include (1) setting the wind schedule 10 minutes ahead of the operating interval based on current wind output, which drastically reduces

[16] *See, e.g.*, 2007 Study at 17, 21, 45-46; 2013 Study at 18.

the wind forecasting error; and (2) dynamically adjusting the quantity of reserves based on information provided in the wind and load forecast and statistical analysis.

3. Netting the Variability and Scheduling Error of Generation and Load.

Another primary source of error in Idaho Power's 2013 Study is the failure to account for the netting between the forecasting/scheduling errors of load and wind, primarily, but also with the deviations of other generators. The approach used in Idaho Power's 2013 Study is to first separately calculate the amount of balancing reserves required for load, have the system optimizer hold that amount of reserves, and calculate the production costs associated with this portfolio. Next, Idaho Power separately calculates the amount of balancing reserves needed for wind, constrains the system optimizer to carry this additional amount of reserves, and then again calculates the production cost associated with the "wind scenario." Comparing the difference between these two production cost runs provides the incremental cost associated with balancing wind and directly feeds into Idaho Power's proposed wind integration rates.

The problem with this approach is that in reality, Idaho Power will not use the arithmetic sum of the individually calculated balancing reserve needs for wind and load because (1) balancing reserves for load and wind are rarely needed at the same time; and (2) scheduling errors of the load and wind will often at least partially cancel each other out. This concept is called "netting."

To explain the netting concept further, consider that Idaho Power is carrying balancing reserves for load every day and every hour of the year. Idaho Power states that it carries balancing reserves equal to three percent of load, and that these reserves are used for in-hour load following requirements, regulation requirements, and load forecast error.[17] The reason that wind and load scheduling/forecasting error should be netted is because sometimes the load

[17] Idaho Power Response to Data Request No. 15.

forecast will be in error in a positive direction (e.g. + 10 MW) and at the same time, the wind forecast error will be in a negative direction (e.g. – 13 MW). In this example, the wind and load error cancel each other out for all but 3 MW and the system operator only needs to dispatch 3 MW of balancing reserves. Three megawatts, in this simple example, would be the incremental balancing reserve need attributable to wind. Idaho Power's 2013 Study proposes to charge wind for all 13 MW of balancing reserves—a significant difference.

When asked if Idaho Power nets the scheduling/forecasting errors for wind with these errors for other generation and load, the Company responded that it does not because "wind and load are not correlated … [thereby] validat[ing] Idaho Power's decision not to net the scheduling errors for wind with the scheduling errors for other generation and load."[18]

We agree that load and wind are not correlated but disagree completely that this "validates" Idaho Power's decision not to net the scheduling error for wind and load. Actually, it is precisely because load and wind are not correlated that Idaho Power *should* net the scheduling errors of these two sources of variability on the system.[19] Only if wind output were always moving in the exact opposite direction of load, by the exact opposite magnitude, would wind's variability not be partially canceled out. Indeed, Idaho Power's own 2007 Study recognized this arithmetic fact: "[b]ecause of the similarity between load and wind with respect to real-time

[18] Idaho Power Response to Data Request No. 3.

[19] Statistically speaking, only if wind and load variations were perfectly negatively correlated with a correlation coefficient of -1.0 would Idaho Power be correct that it is not necessary to net their offsetting variabilities. Well-established statistical principles dictate that the combined variability of uncorrelated sources of variability is equal to the square root of the sum of the squares of the individual sources' variability. As an example, given a fictitious power system with wind variability of 30 MW per hour, load variability of 100 MW per hour, and conventional generator variability of 40 MW per hour, the method for accurately calculating total power system variability is as follows:

Sum of squares variability = $(30^2 + 100^2 + 40^2) = 900+10{,}000+1{,}600= 12{,}500$

Total Power System Variability = Square Root of $(30^2 + 100^2 + 40^2)= 111.80$ MW

This method is essential to accurately capture the statistical fact that the combined variability of several uncorrelated factors is less than the sum of their parts, hence why in the example above the combined variability of 30 MW, 40 MW, and 100 MW is only 111.80 MW and not 170 MW.

operations, it is useful to couple their separate regulation components into a single total regulating reserve level. It is understood that because of interaction between load and wind, a straight arithmetic sum of the separate components results in reserve levels that are inappropriately high."[20] Instead, in 2007, Idaho Power calculated the total reserve requirement by using a root-sum-square methodology, which is much more appropriate.

Indeed, all wind integration studies that reflect best practices in the field calculate reserves based on net load (load minus wind), as it is widely understood that calculating reserves for wind alone results in an incorrect answer. For example, the list of "Common Errors in Integration Analyses" in a 2011 National Renewable Energy Laboratory ("NREL") report by the leading wind integration experts explains why it is critical to analyze net load variability, not wind-alone variability:

> The concept of balancing the net load with conventional generation is well-understood in the integration literature and power system operations. In fact, the NERC Area Control Error (ACE), Control Performance Standards (CPS1&2) standards, Disturbance Control Standard (DCS), and balancing requirements are based upon it. However, within the past year we have seen two integration analyses that have attempted to balance wind and solar in isolation from the remaining load. This means that when wind/solar and load are both increasing, a conventional generator must decrease output to hold the wind and solar constant, but at the same time, generation must increase to meet the increasing load. This does not reflect how power systems are operated and greatly overstates the balancing costs of wind and solar.[21]

Similarly, the IEEE paper, which Idaho Power cites as the authority for much of its 2013 Study methodology, also explains why netting load and wind variability is so important:

[20] 2007 Study Addendum at 19.
[21] Michael Milligan, *et al.*, Cost-Causation and Integration Cost Analysis for Variable Generation at 27 (June 2011), *available at* http://www.nrel.gov/docs/fy11osti/51860.pdf.

> To realistically simulate power system operation, the uncertainties associated with load forecast errors and wind forecast errors are important. Because wind and load forecast errors are generally statistically independent, they do not add arithmetically, and should be developed for the simulation in as realistic a manner as possible...This is because the unit commitment process is done to target the combined loads and wind forecast, whereas the forecast errors will not become apparent until the operating hour.[22]

The Federal Energy Regulatory Commission ("FERC") has also weighed in to explain that a failure to account for net load results in an incorrect calculation of total reserve needs. For example, in August 2009, FERC issued a letter finding that the utility Westar's proposal to calculate wind reserve needs and integration costs in isolation without accounting for the diversity benefits of different resources' variability would incorrectly result in an over-collection of reserve costs.[23]

Westar's own data provided in that proceeding compellingly illustrates that deviations in load and other generation cancel out much of the variability of wind energy. The stand-alone variance of load (variance is proportional to the incremental reserve need caused by each source of variability) was found to be 5 times larger than that of wind, and the variance of conventional generation was found to be 21 times larger than that of wind.[24] As a result, 695 MW of wind

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[22] Erik Ela, *et al.*, The Evolution of Wind Power Integration Studies: Past, Present, and Future at 2 (2009 IEEE)), *available at* http://ieeexpiore.ieee.org/xpi/loqin-isp?tp-&arnunnber=5275981&url=hUp%3A%2F%2Fieeexp!or.

[23] *Westar Energy, Inc.*, Docket No. ER09-1273-000, Deficiency Letter from FERC re Proposed Balancing Area Services Agreement and Schedule 3A, Generator Regulation and Frequency Response Service (Aug. 3, 2009), *available at* http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12099675. In the letter, FERC states "your proposed regulation requirement for intermittent resources reflects the regulation capacity that would be required to balance the output of three intermittent resources in isolation. [Failing to] take into account the diversity among deviations of all system resources and load . . . could result in regulation charges for resources and load that overstate and over-recover total system regulation costs. For example . . . during a 10-minute interval, the output of certain intermittent generation may be declining, while during the same interval, the output of other intermittent or dispatchable generation may be increasing, or load may be decreasing, effectively cancelling out the regulating requirements to some extent on a system-wide basis."

[24] *Westar Energy, Inc.*, Docket No. ER09-1273-000, Informational Filing, OATT, Schedule 3A (Mar. 14, 2014), *available at* http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13484564. The box under Step 2 in the attachment to the filing reports the variances of wind, load, and conventional

energy only incrementally increased the total regulation reserve need for the Westar system by 3 MW.[25]

4. Grid Operating Reforms Would Substantially Reduce Integration Costs.

Wind integration costs are largely caused by obsolete grid operating practices. For example, analysis conducted as part of the Puget Sound Energy wind integration case before FERC confirmed that moving from hourly scheduling to 30-minute scheduling intervals with a 10-minute forecast lead-time would have reduced the wind reserve need by more than 60%.[26] In addition, regions with efficient grid operating practices see much smaller integration costs. Data from ERCOT indicate that the cost of integrating more than 10,000 MW of wind generation is less than $0.50/MWh of wind energy, thanks to its large grid operating area and practice of dispatching generation at five-minute intervals and setting wind schedules based on persistence forecasts from 10 minutes before real-time.[27] As shown in the chart below, regions with fast sub-hourly scheduling have much lower integration costs than regions with hourly scheduling.[28]

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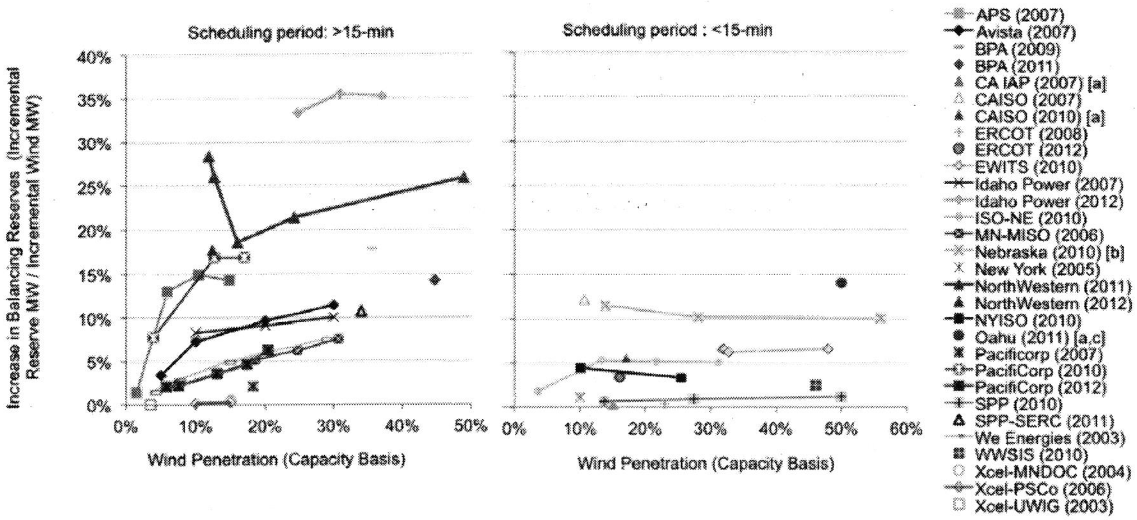
generation (RBASE Generation), and for the calculations above the variances of "inside wind" and "outside wind" are summed.

[25] *Id.* Subtracting the wind variance from the calculation in the box labeled "Regulation Requirement" and taking the square root of that sum without the wind variance included yields a total reserve need of 129.6 MW, versus 132.5 MW with the wind resources included.

[26] *Puget Sound Energy*, Docket No. ER11-3735-000, Protest of American Wind Energy Association and Renewable Northwest Project at 13 (July 5, 2011), *available at* http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12700546.

[27] Mark Alhstrom, A Market Perspective on Forecast Value at 5-8 (Feb. 26, 2013), *available at* http://www.uwig.org/slcforework/Ahlstrom-Session1.pdf.

[28] Ryan Wiser and Mark Bolinger, 2012 Wind Technologies Market Report at 64 (USDOE Aug. 2013), *available at* https://www1.eere.energy.gov/wind/pdfs/2012_wind_technologies_market_report.pdf.



Moreover, the chart indicates that the wind reserve levels indicated in Idaho Power's 2013 Study (light blue line near the top of the left panel) are an extreme outlier, even among other utilities with inefficient operating practices. Idaho Power is holding around 35 MW of reserves for every 100 MW of wind capacity, while all other studies for utilities with inefficient operating practices have found a reserve need of less than 25 MW for every 100 MW of wind capacity at that level of wind penetration. In fact, most studies (including Idaho Power's 2007 Study) are under 12 MW, or one-third of the amount calculated in Idaho Power's 2013 Study. For utilities with efficient operating practices, all studies found a reserve need of less than 12 MW for every 100 MW of installed wind capacity at those wind penetrations. This highlights the impact of Idaho Power's incorrect assumptions on its calculated reserve need and therefore its calculated wind integration cost.

A number of studies have documented that reserve needs and costs are drastically reduced when balancing area operations are coordinated and dispatch intervals are reduced, as they would be under an Energy Imbalance Market ("EIM"). For example, the Northwest Power Pool Market Assessment and Coordination Committee has studied this issue and found that participating in an EIM would reduce Idaho Power's reserve requirement by 29-65%,[29] and would reduce the Company's operating costs by $2.418 million per year.[30]

When asked if the Company has analyzed the costs and benefits of joining the CAISO-PacifiCorp EIM in 2015, Idaho Power responded that it has not, primarily because it "does not have firm transmission rights to access the California market."[31] However, Idaho Power is well connected with PacifiCorp's transmission system, and PacifiCorp is a leading participant in the CAISO-PacifiCorp EIM. This transmission access to PacifiCorp's system would be sufficient to join this EIM effort and reap the associated benefits.

Because integration costs are largely caused by outdated grid operating practices, it is unreasonable to allocate these costs to wind generators. Instead, the entity responsible for setting its grid operating procedures should be required to take steps to reduce its integration costs, since it is best positioned to mitigate these costs by changing its operational practices. As a transmission provider, Idaho Power is required to comply with FERC Order 764, which requires transmission providers to implement grid operating reforms before being allowed to impose integration charges on wind generators. Although Order 764 is not directly applicable to the integration charges assessed against wind QFs in the PURPA context, the reforms that Idaho Power is already required to implement under Order 764 should be applied to the Company's integration of wind QFs to bring down those costs.

When asked about operational tools, Idaho Power explained in its data response that it has "adopted a wind forecasting tool which has improved forecasting accuracy of wind

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[29] Northwest Power Pool Members' Market Assessment and Coordination Initiative, Final Phase 1 Report at Attachment 3, Table 1, p. 28 (Oct. 21, 2013), *available at* http://www.nwpp.org/documents/MC-Public/MC-Initiative-Final-Phase-1-Report-Final-for-Posting.pdf.
[30] *Id.* at 15.
[31] Idaho Power Response to Data Request No. 7.

generation on both the day-ahead and hourly forecast basis."[32] We support the development of this tool and understand that it has increased the efficiency of Idaho Power's ability to integrate wind considerably. We are perplexed, however, as to why the capabilities of this tool do not factor into Idaho Power's 2013 Study methodology—nor do they seem to factor into the wind integration rates and charges proposed in the Company's Application. Wind integration rates and charges should be going down to reflect the efficiency improvements resulting from the forecasting tool and other operational tools available to the Company. Instead, they are moving in the opposite direction.

5. Adjustments to the Company's Rate Calculations to Account for Study Flaws and Changing Market Prices.

Due to the methodological errors in Idaho Power's 2013 Study, it makes more sense to use the 2007 Study as guidance in this docket, especially for determining the incremental reserve requirement associated with future wind generation. Although the 2007 Study is generally superior to the more recent study, one useful component of the 2013 Study is the updated market price data. The market price indices Idaho Power used in the 2013 Study average at $40.98, a 42% decrease from what was used in the 2007 Study. The decrease in market prices suggest that the Idaho Power's wind integration costs should be lower today than they were in 2007 because the opportunity cost in the market is the primary basis for how Idaho Power values the incremental balancing reserves it allocates to integrating wind.

The 2007 Study Addendum also provides useful guidance and data points. A sensitivity analysis in the Addendum estimates that for 600 MW of wind, and assuming average market prices of $44.44—prices that are 7.7% higher than what Idaho Power is projecting today—the wind integration cost would be $6.33/MWh. Adjusting the $6.33 rate for the lower market prices

[32] *Id.*

seen today yields a rate of $5.84/MWh ($6.33 - ($6.33 *.077)). This rate of $5.84/MWh should be considered the ceiling for Idaho Power's wind integration costs going forward. There are several methodological improvements, operational tools, and market reforms that would further decrease this cost of $5.84:

- Neither the 2013 Study nor the 2007 Study accounted for the scheduling error of conventional generators, or the expected interconnection of solar generation on Idaho Power's system.
- The 2013 Study does not include the benefits of Idaho Power's new wind forecasting tool.
- FERC Order 764 requires all transmission providers, including Idaho Power, to offer 15-minute scheduling, and liquidity in this short-term market is increasing.
- Energy Imbalance Markets are being widely discussed in the West, and Idaho Power may be able join an EIM as soon as October 1, 2015.

Taking into account these other factors, we think a reasonable integration cost for Idaho Power is $5.30/MWh, which is consistent with what other transmission providers in the region have calculated. However, our calculations are based in part on limited data from Idaho Power, and more analysis may be required to arrive at accurate wind integration rates. We recommend that at a minimum, the Commission refrain from approving Idaho Power's proposed wind integration rates and charges until the Company revises its 2013 Study to address the significant methodological flaws and analyze costs and benefits of the operational reforms we have identified.

IV. CONCLUSION

WHEREFORE, Renewable Northwest and AWEA respectfully request that the Commission decline to approve the Company's proposed wind integration rates and charges that would apply to any new QFs or integrated resource plans until such time as Idaho Power revises its Wind Integration Study to address the flaws identified herein.

DATED this 2nd day of July, 2014

K&L Gates, LLP

By______________________________
Teresa Hill
Attorney for AWEA and Renewable Northwest

CERTIFICATE OF SERVICE

I hereby certify that on the 2nd day of July, 2014, a true and correct copy of the foregoing COMMENTS OF RENEWABLE NORTHWEST AND AMERICAN WIND ENERGY ASSOCIATION, Case No. IPC-E-13-22, was served by electronic mail to:

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